Chamber Lift- A Technology For Producing Stripper Oil Wells

during the Period 05/15/2001 to 11/30/2002

By

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Bretagne, G.P., Lexington, KY

April 20, 2003

Work Performed Under Prime Award No. DE-FC26-00NT41025
Subcontract No. 2037-TPSU-DOE-1025

For
U.S. Department of Energy
National Energy Technology Laboratory
P.O. Box 10940
Pittsburgh, Pennsylvania 15236

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DISCLAIMER

ABSTRACT

The largest expense associated with the operation of most stripper wells and many stripper gas wells is the lifting costs associated with the removal of fluids from the wellbore. To address this problem, a chamber-lift system was proposed as an alternative to conventional lift systems such as rod pumping. The process involves the injection of gas into the oil column via a small diameter tubing string that is set in the production tubing. The gas then displaces the accumulated fluid to the surface via the annular space between the injection string and the production string. The process is controlled using a sensor and motor valve located at the surface.

A project that called for a field demonstration of the process, the fabrication and testing of a laboratory prototype, and the modeling of the process using hydrodynamic computer model was initiated.

An experimental wellbore apparatus was constructed to simulate the chamberlift system. The laboratory model provided for the observation of reservoir fluids accumulating in the wellbore and the removal of these fluids with a surface compressor. Initial wellbore fluid levels, various wellbore pressure points and surface flow rates were generated as a function of different reservoir and injection gas pressures. Tests were conducted using mineral oil and crude oil obtained from the Big Sinking Field located in Kentucky.

The physical phenomena observed in the experiments are consistent with those reported in the literature for other types of gas-lift. The experimental data that are reported in this work will be used in validating the mathematical model. The work that remains includes additional field testing and mathematical modeling.

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1.0 INTRODUCTION

1.1 Introduction

When first drilled and completed, most wells will flow naturally due to high reservoir pressures. However, during the life of the well, the formation pressure will drop to a point where the flow of oil and gas will either cease or decline to the point where it is uneconomical to continue production. In most cases, as much as 60% of the original oil in place has yet to be produced. At this stage of production, employing artificial lift methods will allow for further economical production of the reservoir. Artificial lift is defined as any method employed in oil well production as a supplement to reservoir energy when the natural energy can no longer sustain production of crude oil from the reservoir to the surface [Osuji (1994)]. Approximately 90% of all oil wells in the world are produced with some kind of artificial lift technique [Chacin and Intevep (1994)]. The second most common method is gas lift, second to only the rod lifting method, which has been in use since the late 1800's.

Gas lift is separated into two main categories. These are the continuous and intermittent gas lift techniques. Continuous gas lift works by constantly injecting high pressure gas into the well to help force the formation fluid to the surface. This method is the more common and is used in wells around the world. However, once the reservoir pressure depletes to a certain point, continuous gas lift will not function, because rather than lift the fluid it will force the fluid back into the formation. At this point in the production life of the reservoir, intermittent gas lift can be a useful technique for continuing production. One intermittent gas lift scheme is referred to as the chamberlift system. There are two types of chamberlift systems. One type involves inserting a bottle-like structure into the largest pipe, which collects the fluids. The other type operates by inserting a dip tube through the smallest pipe and producing the fluids up through it. The purpose of the chamberlift system is to reduce the required flowing bottom hole pressure in order to permit the entry of formation fluids into the wellbore. This system is ideal for a mature reservoir which has the characteristics of low formation pressure and a high productivity index. The use of a chamberlift system offers many advantages over other artificial lift methods, but there are some disadvantages as well.

1.1.1 Types of Chamberlift Installations

There are two general types of chamber installations. These two types are the typical two packer chamber installation and the insert chamber installation [Brown, Vencil et al]. Both types have advantages and disadvantages. Generally, the type of chamber installation is determined by the type of well completion.

The two packer chamber installation uses the annular space for the accumulator. This type of chamber installation is installed to allow for large storage volumes of liquids with a minimum amount of back pressure on the formation. However, the bottom packer must be set just above the perforated interval or open hole completion [Brown, Vencil et al].

The insert chamber installation is usually made from pipe and is used instead of the two packer chamber installation. This type of installation is normally used and works best in wells which have an open hole completion or long perforated intervals. Its greatest benefit is that it takes full advantage of the input flow characteristics, especially the very low bottom hole pressure. However, its one disadvantage is that it is made small to fit inside of the casing string. Therefore, it will hold more volume than the same length of tubing, but not as much as the two packer installation [Brown (1980)].

A dip tube may also be inserted into an insert chamber installation. This addition will allow the point of gas injection to be much lower, hence allowing for more liquid production. During a normal production operation of this kind, the gas is injected down the annulus formed by the dip tube and the insert chamber and the liquid is pushed up through the dip tube and is produced at the surface through the tubing above the chamber.

There are a variety of other installations that are a variation of the two packer and chamber installations. These variations in design are used to deal with certain problems such as formation gas, sand removal, open hole wells, and ultra-slim well completions. One such variation is the reverse flow chamber installation. This new concept allows upward venting of all formation gas by injecting lift gas down the tubing string and producing the liquids up the annulus between the casing and tubing strings. This design allows the formation gas to vent into the tubing through the same opening where the fluids are produced. This method appears to be a good choice for wells with high formation gas-oil ratios [Brown (1980)].

Another variation is a special chamber installation for sand removal. In this installation, the standing valve is extended up to be located in the tubing string. This will give the sand ample space to settle around the standing valve, as the fluid enters the chamber through this opening, instead of actually plugging the valve. This also allows for the standing valve ball and seat to be washed clean of the sand when the chamber is emptied with the lift gas. It is suggested in this case to have the perforations kept as close to the top of the packer as possible. This installation has proven to be successful when other installations have failed because of excess sand production [Brown (1980)].

A one packer installation has been another variation that has been successful in open hole wells with small diameter casing. This installation has the advantage of the added volume compared to the insert chamber installation. Normally this installation will exceed the production of other intermittent installations, but it is not normally recommended because of its instability [Brown (1980)].

Another type of installation is inserting the chamber above the packers. This is done to prevent or minimize certain problems such as sand production. This variation has proven to work well, but its major disadvantage is that it contains less overall volume than the two packer or normal chamber installation [Brown (1980)].

Macaroni installations are used in wells that are completed with smaller than normal casing outside diameters (less than 3.5 inches). They are referred to as “macaroni” strings, because of their unusually small diameter. The diameter of these macaroni strings is limited to the maximum outside diameter of the casing string and the outside diameter of the gas lift valves. This type of installation works well for producing one or both sides of a parallel dual string. Separate gas controls for each string are common and it eliminates the problem of lifting both strings from a common source. The most common disadvantage of these macaroni installations is that the small tubing sizes limit the production capacity [Brown (1980)].

1.1.2 Chamberlift Installation Equipment

Converting a production well from a continuous gas lift system, or even from another artificial lift method, into a chamberlift installation is a rather simple operation. Even the conversion of a naturally producing well into a chamberlift installation does not prove to be a difficult task. The most difficult part of the transition is trying to optimize the chamberlift installation once it has been converted. As mentioned above, there are numerous types of chamberlift installations. It is up to the operator to decide which installation would work best for the given well completion type and formation conditions. However, the basic equipment needed for these installations is very similar, no matter which installation is chosen. The additional equipment includes: a surface compressor, gas lift valves, a standing valve and a differential valve (or the bleed valve). Also, depending on the type of chamberlift installation that is chosen, an insert chamber, an additional production tube or dip tube, and an additional set of packers could be required.

Based on the type of installation, a type of unloading valve must be chosen. Once this valve is chosen, they must be spaced up the well from the bottom, with spacing depending on the available operating gas pressure and kick-off pressure. An operating pressure must also be selected for the valve. This pressure will be affected by two variables: the available operating compressor pressure and the feed-in rate of the fluid into the wellbore. When setting this valve operating pressure, allow for 150-300 psi differential between the opening pressure of the valve and the total load in the tubing. Traditionally, the higher the differential, the higher the percentage of recovery [Brown (1980)].

A differential valve, used for the bleed valve, must also be selected. The selection of this valve is largely based on the gas to liquid ratio (GLR). The higher the GLR, the larger the opening should be on the valve. The differential on this valve should not be too high. Also, as wells start making water, it is crucial that the opening in this valve be large. The reason for this large opening is that the pressure across the valve must be maintained when the gas enters the tubing. It has been shown that a 5/16 inch bleed valve is not large enough to prevent pressure loss across the valve when the well has started to make water [Mukherjee et al (1986)].

Other equipment variations such as the size of the compressor, the injection pressures, the cycle times, the tubing inside diameter, the flowline inside diameter, and the separator pressure are well specific. Therefore, the well operators should tailor each variation to fit their specific well.

1.1.3 Chamberlift Installation Production Procedure

The following section describes the general procedure used when producing from a chamberlift installation. When the chamber is filled with formation liquid, the injection gas is introduced into the wellbore. This causes the chamber operating gas lift valve to open and the standing valve closes. The liquid in the chamber annulus is U-tubed into the dip tube and the tubing above the chamber to form the initial slug length. The liquid slug is then forced to the surface through the tubing above the chamber. Not all of the initial slug is produced because of injection gas breakthrough and the friction caused by the pipe walls. This results in liquid fallback during the production of the slug.

The reservoir pressure continues to build as the standing valve remains closed during the production of the liquid slug. Formation fluids continue to enter the annulus created by the chamber and the outer casing. However, the formation fluids can not enter the chamber while the standing valve is closed. After the liquid slug surfaces, the injection gas is turned off and the remainder is exhausted into the flowlines and the flowing bottom hole pressure in the chamber decreases. The standing valve opens when the pressure in the chamber becomes less than the formation pressure around and beneath the chamber. The liquid in the annulus flows into the chamber first, followed by the formation gas which has risen above the liquid. This process continues until the pressure in the chamber is equal to the pressure in the annulus at the level of the standing valve. When this occurs, the flow into the chamber ceases and the entire process is repeated [Winkler (1999)]. Depending on the well set-up, the gas can be either introduced into the annulus and the liquid is produced through the inner tubing or the gas can be introduced through the inner tubing and the liquid is produced up the annulus. Both methods have proven to work very successfully.

The volume of gas and pressure at which the gas is injected is dependant on numerous variables such as the depth of the producing zone and volume of liquid in the annulus. Also, the cycle time is dependant on the inflow characteristics of the formation.

1.2 Discussion of the Problem

In many areas of the world, the chamberlift installation has proved to be a very economical method for producing oil and gas. This is especially true in mature fields when the reservoir pressure has decreased to the point where the wells have ceased to flow naturally and most artificial methods will no longer work. Although this technology has been around for many year, the primary reason that the chamberlift installation has not gained widespread acceptance and usage in the oil and gas industry is because its highly transient nature has made it very difficult to model. Therefore, predicting the cyclic characteristics and the behavior of the whole production system is nearly impossible [Liao et al (1995)]. Another extremely difficult task is trying to optimize this system when it is installed in numerous wells within a field and there are only a few compressors available to supply gas.

The current design method of a chamberlift installation system is more of an art than a science. Therefore, most methods are based on empiricism and consist mainly of rules-of-thumb. Research in this area is rare compared to the area of continuous gas lift. White et al (1963) attempted to simulate the motion of a finite slug of liquid propelled to the surface by high injection gas. On the other hand, Brown and Jessen (1962) conducted extensive field testing in 1962 and to develop empirical relationships for intermittent gas lift. However, these two approaches had distinct discrepancies in their results and today most modern intermittent gas lift designs use Brown and Jessen's relationships. Neely et al (1973) and Deschner and Brown (1965) conducted extensive work in attempting to optimize the intermittent gas lift system. Such things as time rate behavior of the casing gas pressure and volume, the flow of gas through a gas lift valve, the liquid slug velocity, the amount of liquid produced as well as the amount left behind, and the pressure gradients during the process where all variables that were studied [Neeley et al (1973)].

However, these studies did not take into account the effects of liquid density in their results. These tests were also conducted using the general intermittent gas lift concepts with a limited variation in liquid composition. They did not consider the idea of a chamberlift installation. Finally, most published experimental work, both in the laboratory and with field implementation, deals with the idea of high productivity index reservoirs with high liquid flow rates. There has not been much work done in the area of applying the chamberlift installation to reservoirs with low productivity index wells and extremely low flow rates (less than a few barrels produced per day, per well).

One of the most important parameters to determine, when optimizing the chamberlift installation system, is the well inflow capability. The well liquid production potential is determined by the static reservoir pressure and the productivity index. Knowing this productivity index, other variables such as optimum cycle time, injection pressure, and injection pressure levels can be calculated [Hernandez et al (1998)]. Currently, most chamberlift installations are not optimized, hence they do not achieve their full production potential. However, as a few cases have shown, when the chamberlift installation system is optimized, its production results are greater than other artificial methods used in similar situations.

1.3 Objective of the Investigation

The primary goal of this study is to optimize the chamberlift installation system for reservoirs with low formation pressure, low productivity index and low liquid production per well (less than a few barrels per day). This study will also consider various liquid compositions and reservoir pressures. In order to do this, an experimental wellbore apparatus was constructed to simulate the chamberlift production process. A test matrix was constructed to conduct several tests. With a given liquid composition and reservoir pressure, the injection gas pressure was varied in order to find an optimum ratio between the reservoir pressure and the gas injection pressure. Also, the tests were run using various volumes of liquid within the annulus in order to see how the results varied. Pressure measurements were taken at the top and bottom of the wellbore. Also, the liquid fall-back, which is a measurement of the system's overall efficiency, is measured within the apparatus.

Development of a broad database is another objective of this work. The results of this database can then be analyzed using various simulation models. The results from the model can be compared to the lab scale apparatus to see if there are any similarities. Furthermore, experimental studies at the scale model level will provide insight for developing an effective strategy for implementing the chamberlift installation at the field level.

2.0 LITERATURE REVIEW

2.1 Origins of the Chamberlift Installation

It is believed that air lift got its start when oil companies started experimenting with it in 1846 [Osuji (1994)]. Air lift continued to be successful until the mid 1920's when gas replaced air and gas lift became the most widely used application.[1] Early gas lift installations were used strictly for continuous flow, with the major pitfall being that only one gas injection point was used around the tubing string. This problem was later solved with the invention of numerous kinds of "kick-off valves" [Osuji (1994)].

Shortly after gas lift was introduced, intermittent gas lift was first used in the Seminole Field in Oklahoma in 1926 [Brown (1982)]. This method was fairly successful and led to a whole new way of approaching gas lift as an artificial lift method. It was found that the intermittent gas lift method worked well for depleted reservoirs which had pressures so low that continuous gas lift would no longer work.

However, it is unsure from the literature when the first commercial chamberlift instillation was used. Most authors would agree that this technology has been around for over 40 years. However, the literature suggests that the chamberlift installation technology has only been applied around the world for a little over twenty years [Gasbarri and Marcano (1999)]. As mentioned earlier, White et al (1963) and Brown and Jessen (1962) were the first two publications on the idea of intermittent gas lift. However, White et al's model results did not match the field results of Brown and Jessen's, causing a great need for research in this area.

Some years later, it was reported that the chamber installation was having rather phenomenal success in a few applications around the world. For example, some installations were lifting up to 400-500 barrels/Day from as deep as 11,000 feet. Another example was that a chamberlift installation was lifting 600-700 Barrels/Day from depths of 6000-7000 feet [Brown (1967)]. In most of these cases, extremely low bottom hole pressure readings were recorded. Therefore, when optimized, the chamberlift installation can prove to be very successful.

2.2 The Need for Chamberlift Installation Optimization

Since the first application of intermittent gas lift in the Seminole Field in Oklahoma, the use of this method has been extended around the world. There are numerous other case histories documented in the literature [Brown and Jessen (1962), White et al (1963), Deshner and Brown (1965), Brown (1967), Neeley et al (1973), Brown (1980), Brown (1982), Osuji (1994), Liao et al (1995), Hernandez et al (1998), Hernandez et al (1999) (Paper No. 053968), Hernandez et al (1999) (Paper No. 052124)]. However, there have only been a handful of cases where the chamberlift installation has been used. [Brown, Vencil et al, Hernandez et al (1999) (Paper No. 056664), Winkler (1999), Gasbarri and Marcano (1999),]. Even when this type of installation is used, the design for such a system has been determined by field experience, rules-of-thumb, trial and error, simplified design models, or any combination thereof. As stated earlier, the highly transient nature of the chamberlift installation or all intermittent gas lift methods, for that matter, have made it very difficult to predict the production outcome. Consequently, field optimization is difficult to achieve and maintain and the benefits of the chamberlift installation have not been fully realized. As previously mentioned, there are a few major factors that determine the optimization of the chamberlift installation. They include well inflow capability, venting of formation gas, determining the correct cycling time, and determining the optimum ratio between the gas lift pressure and the reservoir pressure.

3.0 EXPERIMENTAL APPARATUS AND PROCEDURE

3.1 Experimental Apparatus

A laboratory-scale wellbore model was constructed to simulate the gas lift phenomenon that takes place in a chamberlift installation operation (see Figure 3.1). The model was designed to permit liquids to be lifted to the surface, via the inner production tubing or dip tube, at various gas injection pressures. These parameters could be varied to simulate different reservoir conditions and liquid levels within the wellbore. Important design features incorporated into the apparatus include:

1. A dip tube was inserted inside of the production tubing to represent a type of insert chamber installation. The installation is designed so that the dip tube is a few inches shorter than the production tubing. As the fluid enters the wellbore, it ascends into both the dip tube and the annulus created between the dip tube and the production tubing. This annulus represents the insert chamber itself. The dip tube and production tubing were made of steel pipes connected with steel couplings.
2. A standing valve was placed below the chamber so that it remains open when the fluid is entering the wellbore. The standing valve then closes when the gas lift pressure is introduced into the system. This prevents the fluid from being pushed back into the reservoir.
3. Pressure transducer devices[1] were located at the top and bottom of the wellbore. These devices recorded the pressure in the annulus every half second, throughout the experiment. These devices were wired to a box (National Instrument) and emitted a voltage output which was converted to a pressure reading.

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1. Omega Engineering Inc., Stamford, CT

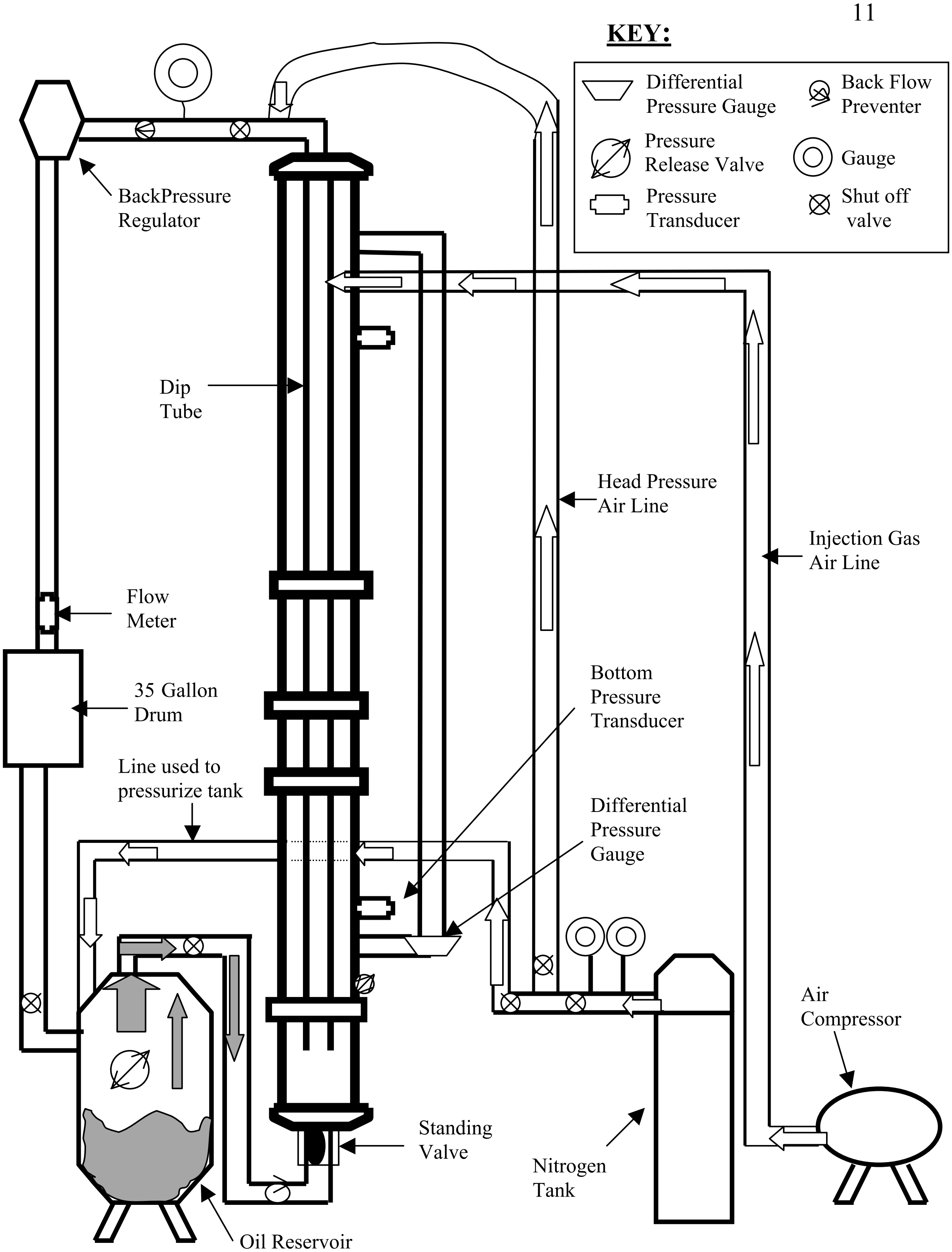

Figure 3.1: Schematic of Experimental Apparatus

4. A differential meter[1] was place on the wellbore to read the difference in pressure at the top and bottom of the apparatus. This device was also wired to the box and its output was converted to a pressure reading. This reading also gave a precise understanding of how much liquid was in the annulus at the start of the test.
5. A back pressure regulator[1] was placed at the surface to regulate the pressure within the wellbore. This allowed for a certain amount of pressure build-up, while the liquid entered the wellbore. The back pressure regulator was set in such a way that the device would not be overcome by the pressure inserted within the wellbore from the liquid entry, but it would allow flow once the gas lift pressure was introduced. The regulator would allow flow through it once the gas lift pressure was introduced, because this pressure was greater than that level of pressure required to overcome the regulator.
6. A flow meter[1] was placed at the surface to measure the flow of fluids being produced. This meter was placed within the string of pipe that connected the back pressure regulator and the barrel which collected the fluids. This meter was also wired to the box and the output was converted to gallons per minute of flow.
7. A pressurized tank was installed on the ground next to the wellbore. This tank was filled with liquids and pressurized to various levels to represent the production formation. The tank was connected to the bottom of the wellbore with various steel pipes and fittings.
8. A digital thermocouple[2] was installed at the midpoint of the wellbore to measure the temperature in the annulus at half second intervals. This temperature is necessary to determine the velocity within the wellbore at various times throughout the test.

The compressed air was supplied by a Grange Electronics compressor that was capable of delivering 1000 standard cubic feet per minute of air at 200 psig. The compressor had two pressure gauges mounted on it. One gauge was mounted on the back and measured the pressure that was built up within the compressor. The other gauge was mounted on the front of the compressor and measured the pressure of the air that was

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2. Omega Engineering Inc., Stamford, CT

exiting the compressor. Valves that controlled both gauges and the pressure levels could be easily changed. The compressed air flowed from the compressor up to the top of the wellbore via a half-inch high-pressure airline. The release of this air was controlled by an on/off valve, which connected a section of the high-pressure hose from the compressor with a high-pressure hose that ran up to the top of the wellbore.

The experimental wellbore consisted of two concentric steel pipes. The outer steel pipe acted as the insert chamber and the inner pipe acted as the dip tube. (reference Fig. 3.2). The overall vertical height of the wellbore was approximately 25 feet (reference Fig. 3.3). The outside diameters of the dip tube and the insert chamber were 1.05-inches and 1.995-inches, respectively. The volumes of the dip tube and the insert chamber were 0.093 and 0.30-cubic feet, respectively. In the experiments, compressed air flows up the high-pressured hose and into the annulus near the top of the wellbore. It then flows down the annulus to where the liquid is resident.

The wellbore was equipped with ports which tapped into the annulus of the wellbore. These ports were spread out in two to three foot intervals and allowed for pressure and temperature readings to be taken at various heights within the wellbore. The pressure transducers had ranges that varied from 0 to 250 psi and extended about 0.125 inches into the annulus to minimize interference with and damage from the high pressures and flow of liquids. The thermocouple was installed at the midpoint of the wellbore to measure the temperature in the annulus. The probe of the thermocouple also extended 0.125 inches into the annulus.

At the top of the wellbore, where the fluids exited the dip tube, a large swivel was used to connect the dip tube to another section of pipe that included a pressure gauge and back pressure regulator. The back-pressure regulator was a spring-loaded ball seat type. Therefore, fluids could enter from the side and the regulator would stop the flow until the pressure reached a present level. When this pressure was attained, the valve would bypass the fluids through the valve and out the bottom of the regulator. The bottom of the regulator was connected to a 35-gallon barrel by a 0.375 inch steel pipe. The drum would collect bypassed fluids during the duration of the experiment. The top of the barrel was open to the atmosphere. Venting the air to the atmosphere was done to prevent pressure build-up in the barrel to a point where failure of the barrel could occur.

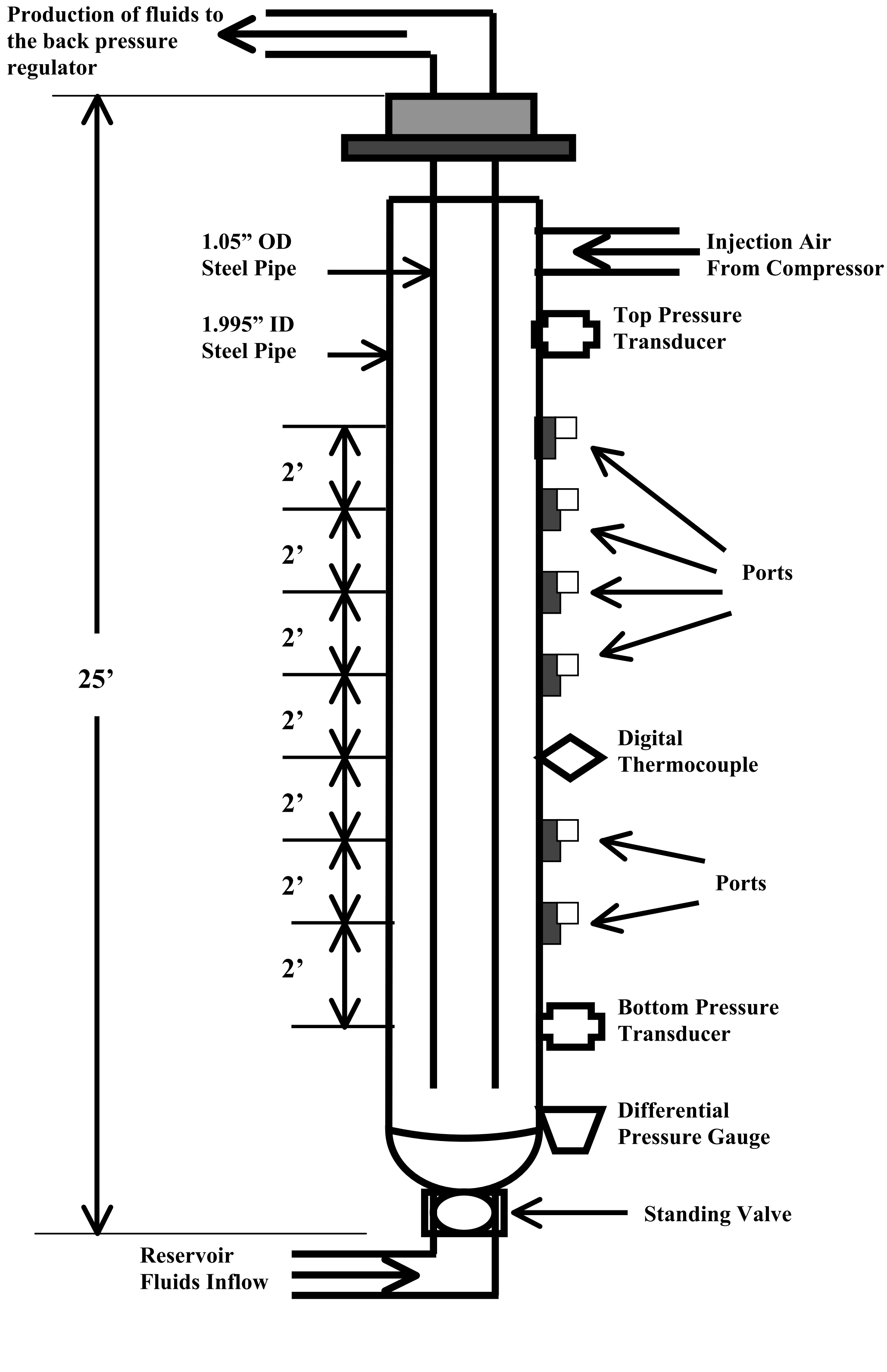

Figure 3.2: Detail of the wellbore section

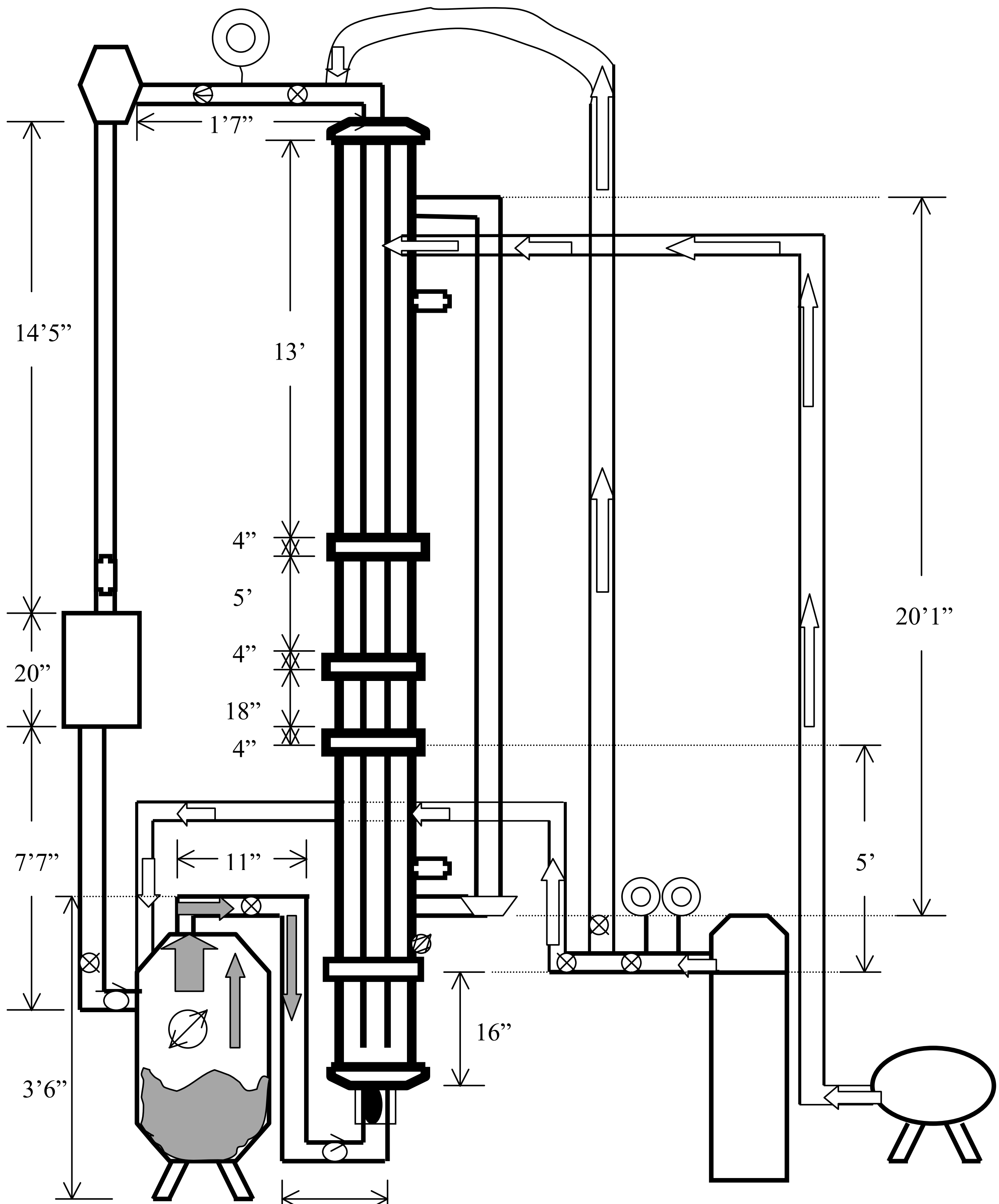

Figure 3.3: Schematic of Experimental Apparatus with Dimensions

To prevent the back-pressure regulator from malfunctioning, it was periodically taken apart and cleaned. This prevented the accumulation of particles within the valve causing it to malfunction during the next experiment. This approach worked well and solved a problem which until solved, was a nuisance.

3.2 Experimental Materials

The liquid compositions used in the experiments were made up of water and oil. The water used was tap water of no specific nature. No salt was added to the water in an attempts to make the water a little denser and more representative of formation waters. For the initial set of test runs, paraffin mineral oil[3] was used as the oil component. This oil had an average specific gravity of 0.845 (at 25^0 C) and an average viscosity of 16.2 (at 40^0 C). This oil was first used to complete a set of tests runs and have results that could be compared to the results of crude oil found in field operations. The liquid compositions used in the experiments ranged from 100% water to 100% mineral oil. The composition was changed by 15% for each new set of test runs. For example, after the set of test runs was completed for 100% mineral oil, the composition was changed to 85% mineral oil and 15% water. This trend was continued until the composition was 100% water. Refer to Table 5.1 for the complete matrix of tests that were completed. This matrix includes the different compositions that were tested as well as the different reservoir and compressor pressures that were used.

After completing the initial set of tests runs, crude oil was used. This crude oil came from an oil field operated in Kentucky by Bretagne Oil and Gas Company. This crude oil had a specific gravity of 0.846. The oil was first filtered using sieving screens to remove any particulate matter that was associated with field production. This was done because the experimental apparatus had dimensions that are smaller than those found in normal production operations. This could have led to failure within the apparatus due to the accumulation of these particles. The test matrix used with the crude oil was the same as that used for the mineral oil tests.

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3. VWR Scientific Products, West Chester, PA

3.3 Experimental Procedure

The objective of the procedure was to determine pressure and temperature measurements in the annulus, and fluid flow rates at the surface for various gas injection pressures. From this information, optimum gas injection pressures could be determined for various reservoir pressures and compositions. The following procedure was used to obtain the data necessary for these determinations:

1. A liquid composition was selected and poured into the tank that represented the production formation. This was accomplished by pouring the liquid composition into the surface barrel and allowing it to gravity feed into the tank.
2. The valve between the surface barrel and the tank was then closed and the tank was pressurized to the specified formation pressure. This was accomplished by using a nitrogen cylinder.
3. The compressor was then started and it pressurized itself to a maximum of 200 psi. The gauge that controlled the exiting pressure from the compressor was then set to the determined pressure. This value ranged from 70 to 85 psi.
4. Two valves were then simultaneously opened. One valve allowed the liquid to flow from the pressurized tank into the bottom of the wellbore, through the standing valve. The other valve allowed gas to flow from the nitrogen tank up to the top of the wellbore and down the annulus. This was done to simulate a head pressure on the liquid as it was entering the wellbore. These two pressures were kept at the same level.
5. Once the pressure and liquid level within the wellbore had reached its maximum value and leveled off, another valve was opened which introduced the compressor air to the top of the wellbore. This compressed air served as the injected gas in a normal gas lift operation.
6. The compressed air flowed down the annulus and forced the formation liquids up the dip tube. Since the compressor pressure was set at a higher value than the back pressure regulator, the regulator was forced open and allowed the fluid to flow through it and down to the surface barrel.

7. Once all of the liquids within the wellbore had been produced, all three valves, which controlled the invasion of liquid formation into the wellbore, the head pressure, and the compressor, were shut off.
8. Pressure readings were taken every half second, during this whole process, from both the top and bottom pressure transducers. These values were recorded.
9. The annulus temperature was recorded for the same length of time. The time and data of these measurements were recorded.
10. The volumetric flow rate of fluids at the surface was also recorded using the flow meter. The time and data of these measurements were recorded.
11. The system was depressurized and steps 4-10 were repeated until the entire volume of liquid within the tank had been depleted.
12. Once the liquid in the tank had been depleted, the reservoir pressure and compressor pressure values were changed and steps 1-11 were repeated until the entire range of pressures had been tested.
13. Once the entire range of pressures had been tested, the reservoir composition was changed and steps 1-12 were repeated for the entire range of reservoir and compressor pressure values.

It was fairly easy to determine the point when all of the liquids had been removed from the wellbore. This point was determined by observing both the differential pressure and flow meter readings. The differential pressure achieved the maximum value just before the compressor air was introduced into the wellbore. As the compressed air U-tubed the liquids from the annulus into the dip tube, the differential pressure continued to drop until it reached the minimum value. This minimum value indicated that there was no more liquid in the annulus. Also, when observing the flow meter, there was an initial surge of flow when the compressor air was introduced. This indicated that the air above the liquid slug was exiting the system through the flow meter. After this, the flow meter readings decreased to a certain value which indicated that the liquid was working its way through the meter. Finally, the flow meter readings shot back up to a high value and stayed constant, indicating that mostly air remained in the system and was exiting through the meter.

Another variable that was measured by the system was the liquid fallback. This variable was observed during the depressurization stage, when the reservoir and compressor pressures had been shut off. As the system depressurized, the differential pressure readings were observed to be increasing from the minimum value obtained when all of the liquid had been removed from the annulus. This indicated that some liquid in the dip tube had not been produced and had fallen back to the bottom of the wellbore. This value varied slightly with the different range of pressures and liquid compositions. Results of this variable can be seen in the graphs which are found in the appendix.

Ambient pressure data were also obtained from the Penn State Meteorology Department Weather Station. The station continuously recorded atmospheric pressure from University Park, PA. Therefore, a corresponding ambient pressure was recorded at the same time each data point was recorded in the laboratory.

It should be noted that barometric pressure data are available in two forms: station pressure and mean sea level (MSL) pressure. Station pressure is the absolute pressure recorded locally at the weather station and the MSL pressure is the local pressure adjusted for mean sea level conditions. MSL pressure is the barometric pressure reported to the public. Station pressure is the pressure that was considered for the ambient conditions of these experiments [Temple (1995)]. For example, when the local absolute pressure is 28.50 inches Hg (965 millibars or 14.0 psia), the barometric pressure at University Park, PA is approximately 29.90 inches Hg (1013.2 millibars or 14.7 psia) [Merritt (1995)].

4.0 ANALYSIS AND DISCUSSION OF RESULTS

4.1 Overview of Data Collection

The purpose of data collection in these experiments was to determine the optimum surface gas injection pressure and volume required for a given reservoir pressure and composition. To achieve this objective, numerous pressure, temperature, and surface flow rates were recorded for each test. Although there were only three different locations used to measure pressure and one to measure flow rates, there were literally thousands of data points recorded during a single test. These data points were then plotted and analyzed. Great effort was made to obtain data that were as accurate as possible. However, due to the apparatus design and the limitations of the instruments, experimental error was unavoidable.

4.2 Limitations of the Backpressure Regulator

The weakest link in the system was the backpressure regulator. The backpressure regulator is located at the top of the wellbore. The main function of this regulator was to hold the designated reservoir pressure and liquid in the wellbore until the injection gas was introduced. At this point, the injected gas would force the liquid through the regulator and into the surface collection barrel. The regulator setting would be somewhere between the reservoir pressure and the injection gas pressure. For example, if the range of reservoir pressures was 45 to 65 psi and the range of injection gas pressures was 70 to 90 psi, then the regulator would be set between 66 and 70 psia. However, the regulator would occasionally collect sediment from the apparatus and would fail to completely close after a test was completed. Consequently, it would fail to retain the reservoir pressure in the wellbore for subsequent tests. This problem was mitigated by removing the regulator and thoroughly cleaning it.

4.3 Summary of Results

In this experimental study, the primary independent variables were reservoir composition, reservoir pressure, artificial wellhead pressure, and injection gas pressure. The primary dependant variables were liquid level within the wellbore, gas volume requirements, surface flow rates, and liquid production. For a specific reservoir composition, a wide range of reservoir pressures, artificial wellhead pressures, and surface compressor pressures were selected. Corresponding liquid levels, surface flow rates and liquid production were recorded. The gas volume requirements can subsequently be calculated using the dimensions of the wellbore and the above mentioned data. Optimum gas volume requirements and surface injection pressures could then be determined for each reservoir composition and pressure.

A summary of experimental parameters, for this study, is shown in Table 5.1. After conducting experimental runs with numerous values for both the reservoir pressures and injection gas pressures, it was determined that it would be best to complete the entire experiment with these ranges. The reasons for this conclusion are as follows:

1. The compressor, which was used for the injection gas, was only capable of injecting up to 140 pounds of pressure.
2. The backpressure regulator was only capable of retaining 175 pounds of pressure.
3. The nitrogen tank, used for pressurizing the reservoir, was only capable of safely injecting 100 pounds of pressure.
4. The tank, used as our reservoir, could only safely hold 100 pounds of pressure.

Once the range of reservoir pressures were determined, a wide range of gas injection pressures were tested and the range of 80 to 95 psi were determined to be the most efficient. The use of pressures less than 80 psi resulted in problems with lifting the reservoir fluids, and the use of pressures greater than 95 psi was inefficient, because the gas would quickly by-pass the fluids. It was observed in this latter case, that less production resulted.

As stated earlier, the entire set of experimental tests has yet to be completed. More specifically, the set of mineral oil tests have been completed, but the crude oil tests are only about 50% completed. However, plots and the analysis of the mineral oil tests have been completed. The only variable yet to be calculated for the mineral oil tests is the overall gas volume requirements for each experiment. In order to do this, we intend to place an instrument over the outlet of the compressor in order to record the velocity of the gas. Once this is accomplished, the gas volume requirements can be calculated using this velocity data along with the pressure of the injected gas and the dimensions of the apparatus. The same procedure will be used for the crude oil tests once they are completed. After the gas volume requirements

Chamberlift Test Matrix									
		100% Oil	85% Oil 15% Water	70% Oil 30% Water	55% Oil 45% Water	40% Oil 60% Water	25% Oil 75% Water	10% Oil 90% Water	100% Water
		Reservoir and Head Pressures (same value)							
Com. Pressure (Gas Injection Pressure)	80 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig
		50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig
		55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig
		60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig
		65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig
	85 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig
		50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig
		55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig
		60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig
		65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig
	90 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig
		50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig
		55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig
		60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig
		65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig
	95 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig
		50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig
		55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig
		60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig
		65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig
		70 psig	70 psig	70 psig	70 psig	70 psig	70 psig	70 psig	70 psig
		75 psig	75 psig	75 psig	75 psig	75 psig	75 psig	75 psig	75 psig
		80 psig	80 psig	80 psig	80 psig	80 psig	80 psig	80 psig	80 psig
		85 psig	85 psig	85 psig	85 psig	85 psig	85 psig	85 psig	85 psig
		90psig	90psig	90psig	90psig	90psig	90psig	90psig	90psig

Table 5.1: Experimental Test Matrix

are calculated for each experiment, the data will be entered into the mathematical model in order to model the fluid flow dynamics. This model has been completed and awaits the entire matrix of experimental data. Upon completion of the modeling, the final results will be applied to actual field tests. These field tests will be conducted by Bretagne Oil and Natural Gas Company in the Big Sinking Spring field, located in Kentucky.

Once the experimental tests using mineral oil were completed, they were graphed and analyzed. Figures 5.1 and 5.2 show the trends of pressure when plotted. It can be seen that these two plots vary greatly. Figure 5.1 shows a test in which there was no breakthrough of gas in the liquid slug. Therefore, this test was more efficient because the time of the injected gas and the liquid fallback was less than that of a test in which there was breakthrough. Also, this type of test resulted in a greater percentage of liquid production at the surface. Figure 5.2 shows a test in which there was breakthrough of gas in the liquid slug. This was less efficient, because it required more gas to produce the liquid slug and the liquid fallback was greater. Hence, there was less overall liquid production at the surface.

The analysis for each test included: determining the liquid level within the wellbore, determining the time of the injected gas, gas lift breakthrough and liquid fallback. Tables A.1 through A.8, in Appendix A, summarize the liquid levels within the wellbore and the time of the injected gas for two tests at each of the determined reservoir and gas injection pressures. It can be seen by analyzing the time of injected gas that some ratios of injected gas pressure to reservoir pressure were more efficient than others. For each table, the highlighted rows are the tests that appear to be the most efficient. It should be noted, however, that the actual gas volume requirements have not yet been calculated for each test, so these results could change. The values for the liquid levels are actual pressure measurements that correspond to a certain height or volume. For example, a liquid level value of 2.0 psi corresponds to an actual volume of approximately 3.0 liters of liquid within the wellbore; and a liquid level value of 2.5 psi corresponds to a volume of approximately 4.0 liters of liquid.

From the analysis of the mineral oil tests, a few important trends have been noticed. As stated in the abstract, most of these trends are consistent with those found in previous literature. Some of these trends include:

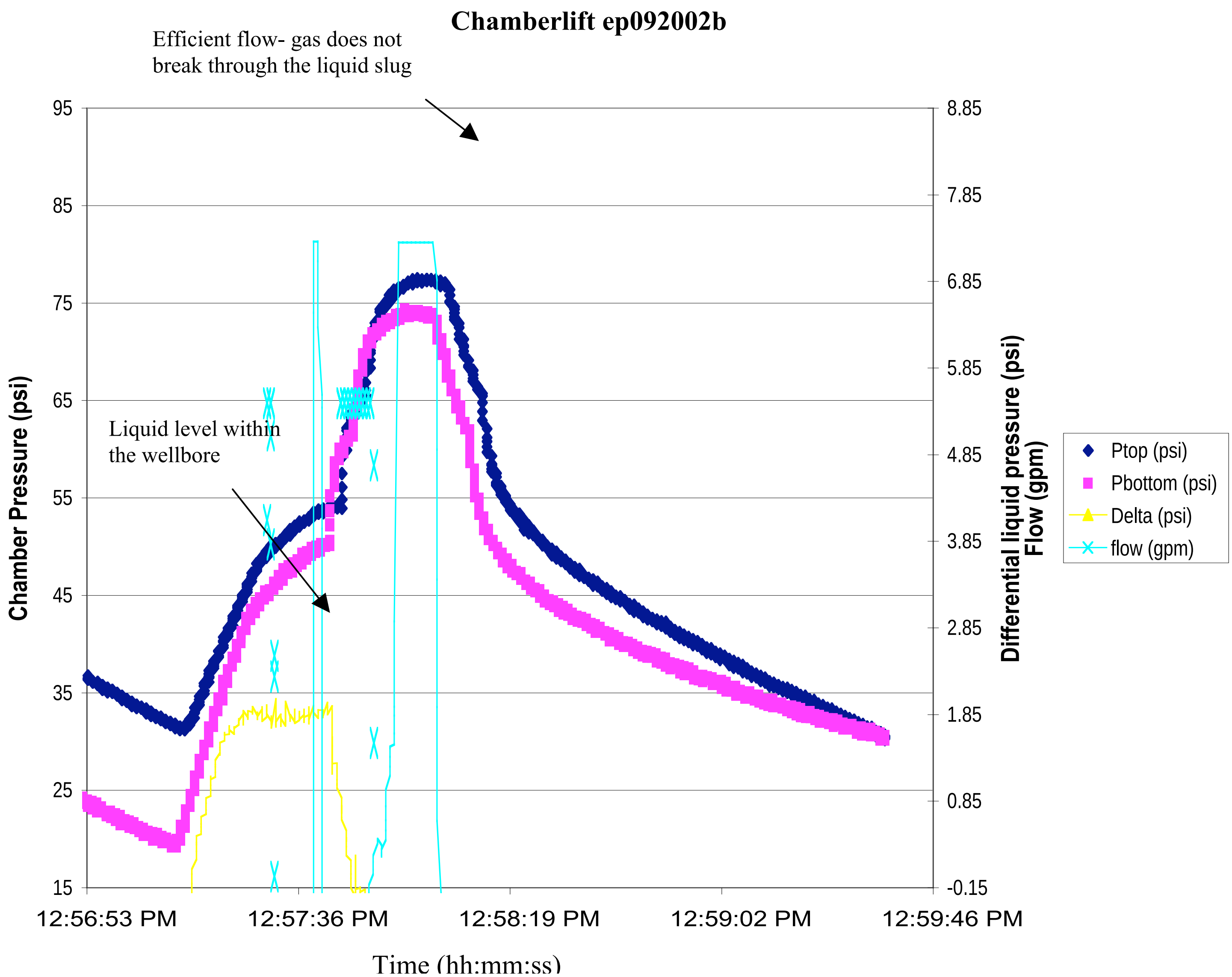

Figure 5.1: Efficient chamberlift test using 70% mineral oil and 30% water.

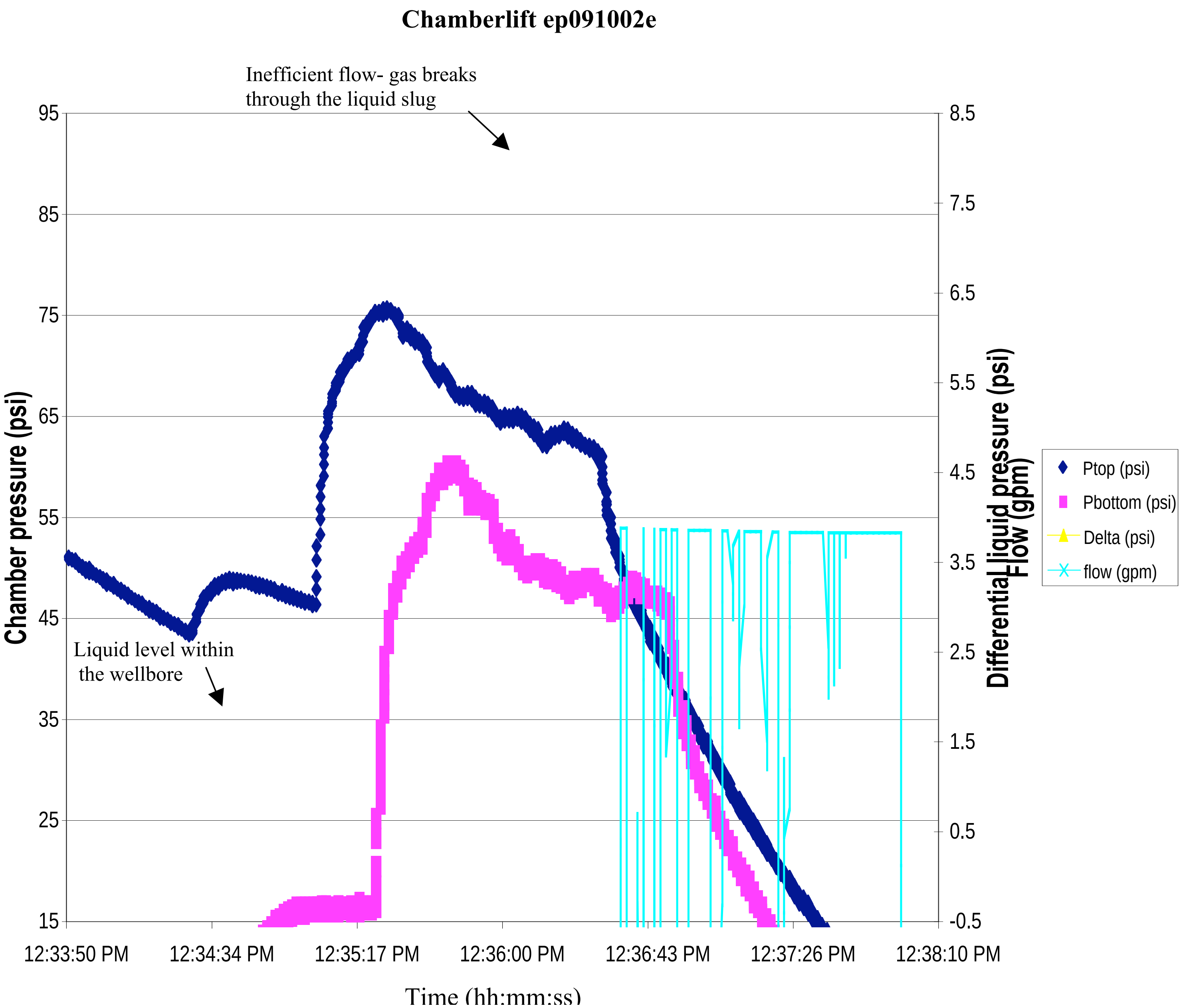

Figure 5.2: Inefficient chamberlift test using 100% mineral oil.

1. There appears to be a small range of efficient ratios between the gas injection pressure and the reservoir pressure. This trend holds true for all reservoir compositions. A ratio that is too small is inefficient, because the gas has difficulty lifting the liquid slug. A ratio that is too large is inefficient because the gas quickly breaks through the liquid slug, causing a large amount of fallback.
2. The height of the liquid column, within the wellbore, has an effect on the overall production and efficiency. Regardless, of the ratios between the pressures, a small liquid column increases the chances of gas breakthrough and less efficient liquid recovery. However, if the liquid column height is excessively large, the lifting of the liquid, by the gas is unattainable, regardless of the pressure ratios. An optimum range of liquid column height for this experimental apparatus was between 7 and 12 feet.
3. The system appears to be less efficient as the percentage of water increases. The exact reason for this observation needs to be further investigated.

In summary, the data generated, thus far, are believed to be accurate and reliable. Also, there are some trends that must be further studied using crude oil, rather than mineral oil, in order to verify the results. When completed, the data should provide a good basis for validating existing and future mathematical models for chamberlift optimization. Also, the information obtained from this research should be useful in designing field scale operations.

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 Summary and Conclusions

The objective of this study is to determine the optimum gas injection pressures and volume requirements for a chamberlift system. This optimization would be done for a wide variety of reservoir pressures and compositions. Once the experimental tests have been completed, the data would be used in a mathematical model to simulate the fluid flow dynamics within the wellbore. Upon completion, these results will be carried out in a field demonstration in order to test their validity.

To date, tests using mineral oil have been completed and tests using crude oil are approximately 50% completed. A mathematical model has been developed and awaits testing using the results of the experimental runs. Thus far, certain trends have been noticed, which are consistent with previously published literature. However, it is believed that the results from this experiment will be more detailed and accurate. The experimental tests should be concluded by the end of April and the results from the mathematical model should be concluded by the middle of June. Further field tests are planned during Phase II.

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APPENDIX A

RESULTS OF MINERAL OIL TESTS

TEST RESULTS							
COMPOSITION: 100% MINERAL OIL							
Test #	Gas Injection Press.	Reservoir Press.	Liquid Level	Gas Injection Time (sec)	Fluid Level	Gas Injection Time (sec)	Comments
0904f	85	55	3.0	32	3.2	33	
0904b	85	45	3.6	38			
0905b	85	60	3.1	29	3.5	37	
0904g	85	65	2.8	31	3.0	28	
0906a	90	60	2.5	114	3.0	142	Breakthru with both peaks
0906b	90	65	2.7	167	3.1	134	Breakthru with both peaks
0906c	90	70	2.8	120	3.2	123	Breakthru with both peaks
0906d	90	75	2.7	101	3.2	122	Breakthru with both peaks
0906e	90	80	3.2	117	3.3	110	Breakthru with both peaks
0909a	90	85	2.3	64	3.2	154	Breakthru with both peaks
0910d	90	90	3.6	128	3.8	144	Breakthru with both peaks
0910e	80	55	2.5	72	3.0	230	Breakthru with both peaks
0910f	80	65	2.8	121	2.9	136	Breakthru with both peaks
0911c	75	55	1.9	110	2.3	135	Breakthru with both peaks
0913a	75	55	2.4	33	2.5	33	Breakthru with both peaks

Table A.1: Liquid levels and gas injection times for tests with 100% mineral oil.

TEST RESULTS							
COMPOSITION: 85% MINERAL OIL, 15% WATER							
Test #	**Gas Injection Press.**	**Reservoir Press.**	**Liquid Level**	**Gas Injection Time (sec)**	**Fluid Level**	**Gas Injection Time (sec)**	**Comments**
0916g	75	45	2.7	28	3.0	31	
0916h	75	50	2.8	37	3.1	58	
0916i	75	55	2.5	32	2.9	25	
0916j	75	60	2.8	28	3.0	43	
0916k	80	45	2.9	31	3.1	40	
0917b	80	50	2.5	22	2.6	35	
0917c	80	55	2.6	21	3.0	24	
0917d	80	60	2.5	21	3.1	28	
0917e	80	65	2.9	25	3.3	28	
0917f	85	45	2.4	18	2.8	21	
0917g	85	50	2.7	21	3.1	27	
0917h	85	55	2.7	21	3,2	25	
0918a	85	60	3.0	23	3.6	27	
0918b	85	65	3.1	25	3.3	27	
0918c	90	45	2.5	18	3.0	25	
0918d	90	50	2.7	19	2.9	21	
0918e	90	55	2.7	18	2.9	21	
0918f	90	60	2.8	20	3.1	22	
0918g	90	65	2.8	19	3.2	26	
0918h	90	60	2.6	32	3.0	28	
0918i	90	65	2.5	29	3.3	45	
0918j	90	70	3.2	37	3.6	41	
0918k	90	75	2.4	24	3.6	45	
0918L	90	80	2.7	41	3.3	37	
0918m	90	85	2.5	36	3.0	45	
0919a	90	90	3.7	60	4.0	58	Breakthru with both peaks

Table A.2: Liquid levels and gas injection times for tests with 85% mineral oil and 15% water. .

TEST RESULTS							
COMPOSITION: 70% MINERAL OIL, 30% WATER							
Test #	**Gas Injection Press.**	**Reservoir Press.**	**Liquid Level**	**Gas Injection Time (sec)**	**Fluid Level**	**Gas Injection Time (sec)**	**Comments**
0919j	75	45	2.4	26	2.8	29	
0919k	75	50	2.6	31	3.5	49	
0920a	75	55	2.5	28	2.8	26	
0920b	75	60	2.3	19	3.0	29	
0920d	75	65	3.8	112	4.6	97	
0920e	80	45	3	43	3.4	37	
0923a	80	50	2.6	34	3.1	36	
0923b	80	55	2.5	26	2.8	25	
0923c	80	60	2.9	59	3.4	37	Breakthru with second peak
0923d	80	65	3.5	32	3.8	48	
0923e	85	45	2.6	36	3.4	76	
0923f	85	50	2.9	26	3.6	39	
0923g	85	55	2.7	26	3.5	44	
0923h	85	60	2.7	67	3.2	36	Breakthru with second peak
0923i	85	65	2.9	45	3.2	27	
0923j	90	45	2.7	25	3.2	26	
0924a	90	50	2.6	44	3.9	80	
0924b	90	55	3.1	68	4	57	
0924c	90	60	3	54	3.5	32	
0924d	90	65	3	23	3.4	31	
0924e	90	60	1.6	22	3.5	63	
0924f	90	65	3	89	3.1	37	
0924g	90	70	2.8	26	3.7	63	
0924h	90	75	2.8	31	4.1	64	
0930a	90	80	3.6	32	4.2	45	
0930b	90	85	3.6	84	4.2	73	
0930c	90	90	4.3	32	4.9	34	

Table A.3: Liquid levels and gas injection times for tests with 70% mineral oil and 30% water. .

TEST RESULTS							
COMPOSITION: 55% MINERAL OIL, 45% WATER							
Test #	**Gas Injection Pressure**	**Reservoir Press.**	**Liquid Level**	**Gas Injection Time (sec)**	**Fluid Level**	**Gas Injection Time (sec)**	**Comments**
0930L	75	45	2.2	22	2.7	23	
0930m	75	50	2.4	27	2.9	27	
0930n	75	55	3.0	37	3.9	36	
0930o	75	60	2.8	40	3.6	26	
0930p	75	65	2.4	24	3.9	28	
0930q	80	45	1.8	18	2.0	18	
0930r	80	50	1.8	19	2.9	24	
0930s	80	55	1.8	18	2.7	22	
1001a	80	60	2.6	32	3.0	25	
1001b	80	65	2.8	25	3.5	29	
1001c	85	45	2.6	20	2.9	20	
1002a	85	50	2.5	21	3.0	25	
1002b	85	55	2.8	34	3.3	27	
1002c	85	60	2.7	26	3.6	29	
1002e	85	65	2.8	24	3.0	24	
1002f	90	45	2.9	25	3.3	27	
1002g	90	50	2.9	21	3.1	29	
1002h	90	55	3.0	25	3.5	26	
1002i	90	60	2.7	22	3.7	36	
1002j	90	65	3.5	35	4.2	35	
1003a	90	60	2.9	32	3.2	35	
1003b	90	65	3.0	33	3.4	48	
1003c	90	70	2.8	60	3.6	39	
1003d	90	75	3.2	30	3.6	31	
1003e	90	80	3.3	28	4.0	31	
1003f	90	85	2.5	45	3.9	40	
1003g	90	90	3.4	34	3.6	33	

Table A.4: Liquid levels and gas injection times for tests with 55% mineral oil and 45% water. .

TEST RESULTS							
COMPOSITION: 40% MINERAL OIL, 60% WATER							
Test #	Gas Injection Pressure	Reservoir Press.	Liquid Level	Gas Injection Time (sec)	Fluid Level	Gas Injection Time (sec)	Comments
1004a	75	45	2.3	22	2.5	24	
1004b	75	50	2.4	21	2.8	25	
1004c	75	55	2.7	23	3.0	25	
1007a	75	60	2.6	23	2.9	28	
1007b	75	65	2.8	28	3.5	31	
1007c	80	45	2.5	24	2.7	24	
1007d	80	50	2.4	20	3.6	17	
1007e	80	55	2.8	35	4.0	30	
1008a	80	60	2.9	24	3.3	25	
1008b	80	65	3.1	24	3.3	27	
1008c	85	45	2.2	16	2.3	17	
1008d	85	50	2.4	18	2.7	20	
1008e	85	55	2.6	19	2.8	20	
1009a	85	60	2.9	18	3.0	19	
1009b	85	65	3.2	21	3.6	24	
1009c	90	45	2.4	18	3.7	22	
1009d	90	50	2.7	18	4.0	23	
1009e	90	55	2.7	18	3.0	20	
1009f	90	60	3.0	18	3.4	22	
1009g	90	65	3.1	19	3.3	20	
1014a	90	60	3.0	30	3.5	34	
1014b	90	65	3.5	33	3.8	36	
1014c	90	70	3.3	29	3.6	31	
1014d	90	75	3.6	61	4.4	34	First peak had breakthru
1014e	90	80	4.8	42	5.0	43	
1016a	90	85	3.5	25	3.8	27	
1016b	90	90	3.7	36	4.2	32	

Table A.5: Liquid levels and gas injection times for tests with 40% mineral oil and 60% water. .

TEST RESULTS							
COMPOSITION: 25% MINERAL OIL, 75% WATER							
Test #	**Gas Injection Press.**	**Reservoir Press.**	**Fluid Level**	**Gas Injection Time (sec)**	**Fluid Level**	**Gas Injection Time (sec)**	**Comments**
1016k	75	45	2.5	23	2.9	25	
1016L	75	50	2.8	23	3.3	26	
1016m	75	55	3.0	24	3.5	27	
1016n	75	60	3.0	23	3.6	26	
1016o	75	65	3.0	26	3.5	28	
1016p	80	45	2.5	21	2.8	22	
1016q	80	50	2.4	19	2.9	20	
1022a	80	55	2.8	18	3.0	22	
1022b	80	60	3.0	22	3.3	23	
1022c	80	65	2.9	23	3.5	24	
1022d	85	45	2.5	20	2.6	18	
1022e	85	50	2.7	20	2.9	21	
1022f	85	55	3.0	22	3.2	21	
1022g	85	60	3.3	21	3.5	20	
1025a	85	65	3.4	19	3.7	26	
1025b	90	45	2.2	17	2.9	19	
1025c	90	50	2.4	17	2.6	16	
1025d	90	55	2.7	18	2.9	20	
1025e	90	60	3.0	18	3.4	19	
1025f	90	65	3.2	18	3.7	19	
1025g	90	60	3.0	24	3.4	26	
1025h	90	65	3.4	26	4.0	30	
1025i	90	70	2.8	22	3.8	27	
1025j	90	75	3.3	24	3.7	26	
1025k	90	80	3.0	23	3.5	26	
1028a	90	85	3.3	26	3.8	29	
1028b	90	90	3.6	27	4.0	30	

Table A.6: Liquid levels and gas injection times for tests with 25% mineral oil and 75% water. .

TEST RESULTS							
COMPOSITION: 10% MINERAL OIL, 90% WATER							
Test #	Gas Injection Press.	Reservoir Press.	Fluid Level	Gas Injection Time (sec)	Fluid Level	Gas Injection Time (sec)	Comments
1029a	75	45	2.4	18	2.7	20	
1029b	75	50	2.5	18	2.8	20	
1029c	75	55	2.7	19	2.9	20	
1029d	75	60	2.5	18	3.0	21	
1029e	75	65	3.0	21	3.5	23	
1030a	80	45	2.5	17	2.8	19	
1030b	80	50	2.6	17	2.8	19	
1030c	80	55	2.5	16	2.9	18	
1030d	80	60	2.5	15	3.1	19	
1030e	80	65	3.0	19	3.4	21	
1030f	85	45	2.9	18	3.6	22	
1030g	85	50	2.6	16	2.9	17	
1030h	85	55	2.6	15	3.0	17	
1030i	85	60	2.7	15	3.0	17	
1030j	85	65	2.6	17	3.0	18	
1031a	90	45	2.6	19	3.9	24	
1031b	90	50	2.5	15	2.7	16	
1031c	90	55	2.7	16	2.9	17	
1031d	90	60	2.0	13	2.1	13	
1031e	90	65	2.0	14	2.2	16	
1031f	90	60	2.5	23	3.3	29	Breakthru with both peaks
1031g	90	65	4.2	38	5.0	53	
1031h	90	70	3.4	29	3.6	32	
1031i	90	75	3.0	25	3.6	27	
1031j	90	80	2.9	23	3.4	24	
1031k	90	85	3.3	24	3.5	25	
1105a	90	90	3.4	29	3.6	32	

Table A.7: Liquid levels and gas injection times for tests with 10% mineral oil and 90% water. .

TEST RESULTS							
COMPOSITION: 0% MINERAL OIL, 100% WATER							
Test #	Gas Injection Press.	Reservoir Press.	Fluid Level	Gas Injection Time (sec)	Fluid Level	Gas Injection Time (sec)	Comments
1111a	75	45	2.6	23	2.8	24	
1111b	75	50	2.7	23	2.9	24	
1111c	75	55	2.6	20	2.9	23	
1111d	75	60	2.9	23	3.1	25	
1111e	75	65	2.8	22	3.5	26	
1111f	80	45	2.6	18	2.7	19	
1111g	80	50	2.6	18	2.8	19	
1111h	80	55	2.7	18	2.9	21	
1112b	80	60	3.2	20	3.5	21	
1112c	80	65	2.9	21	3.5	22	
1112d	85	45	2.3	17	2.7	18	
1112e	85	50	2.8	20	2.9	20	
1112f	85	55	2.8	18	3.0	20	
1112g	85	60	2.8	18	3.2	21	
1112h	85	65	2.9	20	3.5	22	
1112i	90	45	3.0	18	3.5	21	
1112j	90	50	2.8	17	3.4	19	
1112k	90	55	2.9	17	3.0	18	
1112L	90	60	2.9	18	3.5	19	
1112m	90	65	2.9	17	4.1	24	
1112n	90	60	2.5	21	2.9	27	Breakthru with both peaks
1112o	90	65	2.7	24	3.0	28	Breakthru with both peaks
1112p	90	70	2.8	26	3.2	29	Breakthru with second peak
1112q	90	75	3.0	24	3.9	31	
1114a	90	80	2.8	30	3.2	31	Breakthru with both peaks
1114b	90	85	3.1	34	3.8	38	Breakthru with both peaks
1114c	90	90	2.7	34	3.1	36	Breakthru with both peaks

Table A.8: Liquid levels and gas injection times for tests with 100% water. .